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Via E-Mail

Howard B. Bernstein
RPS Program Manager
MA Division of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114

Re: Massachusetts DOER Renewable Energy Portfolio Standard Notice of Inquiry
Jansen Project Number 4416

Dear Mr. Bernstein:

Below are Jansen Combustion and Boiler Technologies, Inc.'s (JANSEN) response and comments regarding the *Massachusetts DOER Renewable Energy Portfolio Standard Notice of Inquiry; Regarding Low-Emission, Advanced Biomass Power Conversion Technologies*.

General Comments:

One of the outcomes of the Renewable Energy Portfolio Standard (RPS) program should be to displace electrical power generated by fossil fuel, not displace existing biomass power generators. Displacing fossil fuel-fired plants will reduce green house gas production, ozone precursor emissions, and minimize the nation's reliance on oil imports.

The process of developing RPS requirements to qualify for Renewable Energy Credits (RECs) has become increasingly complicated with an uncertain financial incentive. Considering the substantial expense involved with retrofitting existing plants to meet the requirements, it becomes unlikely that the legislature's goal of increasing the fraction of "low emission, advanced biomass power conversion technologies" through the RPS statute will be met. To make the program work will require attainable requirements, at reasonable investment levels, with a reliable revenue stream. The proposed revisions to the RPS regulations do not appear to promote a level playing field and a successful outcome. The impression has been given in the NOI that new biomass-fired power plants (or solar, wind, landfill methane, etc.) are favored over retrofitting existing plants. Giving greater incentive to new renewable generation plants would appear to meet the statute's expansion goals. However, if existing plants are excluded from REC qualification and forced out of operation due to unfair competitive forces, then the expansion goals will likely not be met and the net result will be extremely high capital investment for new plants that will replace existing plants. Relaxation of some of the stringent emissions limits will make qualification of RECs more attainable for existing biomass-fired plants.

Responses to Questions from Page 15 and 16 of NOI:

A. In our experience, advances in fuel and air delivery in stoker units have allowed higher boiler firing rates at lower overall air emissions and higher thermal efficiency. These advances, in particular, include development of advanced overfire air (OFA) delivery systems that have higher air flow capacity, require lower static pressure, and generate increased mixing in a zone above the fuel delivery elevation. The results include increased biomass fuel firing with a commensurate reduction in fossil fuel firing, improved combustion stability, more complete burnout of carbon monoxide (CO), volatiles, and char carbon, and reduced ash and char carryover. Lower excess air operation, due to improved combustion efficiency, results in lower nitrogen oxide (NO_x) emissions, lower auxiliary equipment power requirements, and improved thermal efficiency. Advanced computational fluid dynamics (CFD) models have been developed by JANSEN to be used as evaluation and design tools in applying new fuel and air delivery systems to existing boilers. These improvements have resulted in extended operating life and better utilization of existing steam generating plants, avoiding the capital expense of plant replacement.

   Stoker combustion systems with modern OFA systems provide the following advantages over fluidized bed combustion (FBC) systems:

   1. Lower capital cost
   2. Lower maintenance; better reliability; greater capacity factor
   3. Lower parasitic loads (fan horsepower); lower heat rates; better overall efficiencies

B. The definition of Net Heat Rate (NHR) given on Page 9 is not correct. The definition should read “ratio of the total fuel heat input to the quantity of the net electrical power output of the Generation Unit”. Comparing plant NHR is a valid way to demonstrate differences in overall plant efficiency and in defining the impact of parasitic loads on performance. In particular, FBC units will demand significantly higher forced draft (FD) fan power to meet the high static air pressure operating requirements. The high FD fan power parasitic load results in a higher NHR. This is demonstrated by the higher allowed NHR values proposed in Table 1 for FBC units. It becomes clear that the NHR levels are being set to not exclude the FBC technology from consideration as an advanced biomass power conversion technology. The particular benefit that FBC systems offer is combustion of poor quality fuels, but in most new and existing biomass plants, good quality biomass fuel is available and does not require FBC technology.

   It is our opinion that it will be difficult to develop fair protocols to determine NHR for existing plants. Complications, including potential multi-fuel usage, cogeneration, poor turbine/generator efficiency, and actual operating load versus design load, make the determination of NHR difficult to quantify in all cases. All of the 40 units that JANSEN has

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installed advanced OFA systems on have been cogeneration units in the pulp and paper/wood products industry, and therefore do not readily yield NHR for comparison to power generating plants.

A better calculation for boiler system efficiency would be to calculate a net energy conversion factor using the following procedure.

Divide the total fuel energy delivered to the boiler by the total useful energy output. The total fuel energy is determined by multiplying the fuel higher heating value (HHV) by the fuel feed rate. The total useful energy output is determined by subtracting the Btu/hr equivalent of the energy consumed by boiler auxiliaries (FD fans, ID fan, feedwater pumps, etc.) from the net energy produced as steam (steam flow multiplied by the enthalpy difference between final steam and feedwater). The procedure is described by the equation below:

Net Energy Conversion Factor =

$$\frac{HHV\left(\frac{Btu}{lb}\right) * \dot{m}_{fuel}\left(\frac{lb}{hr}\right)}{\left[H_{steam}\left(\frac{Btu}{lb}\right) - H_{Fw}\left(\frac{Btu}{lb}\right)\right] * \dot{m}_{steam}\left(\frac{lb}{hr}\right) - E_{auxiliaries}\left(\frac{Btu}{hr}\right)}$$

The net energy conversion factor would apply fairly to both power generating plants and cogeneration plants, and would not depend on turbine/generator efficiencies.

C. **NO_x Emissions**

It is understood that there is incentive to achieve a substantial reduction in emissions through the implementation of the RPS program and that there is a concern that qualifying existing plants could create an over-supply of RECs in the market and undercut incentives for new plant construction or development of cleaner renewable resources. However, the low emissions levels proposed place a large burden on existing plants to comply with the regulations. At a NO_x emissions level of 0.075 lb/MMBtu, all boilers will be required to install SCR or RSCR systems. If the NO_x emissions rate were in the range of 0.12 to 0.15 lb/MMBtu, then less expensive SNCR technology could be employed while still achieving a significant (approximately 50%) reduction in NO_x emissions.

The very low emissions limits proposed by DOER (e.g., the New Source Performance Standard (NSPS) NO_x limit for new facilities of 0.30 lb/MMBtu is 4 to 20 times higher than the proposed range of 0.015 to 0.075 lb/MMBtu) will require expensive back-end treatment equipment that may not be economically justifiable. Requiring expensive back-end treatment equipment precludes incentives by the industry to develop “more advanced combustion” systems, which is at the very heart of the stated goal of encouraging “advanced biomass power conversion” technologies. Thus, by default, “status quo combustion” will continue to be the norm while the back-end cleanup equipment is relied upon to mask the combustion deficiencies. Poor combustion leads to higher maintenance and operating costs, which results in lower plant capacity factors and reduced efficiencies. A compromise between low

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emission values and a basic incentive to encourage more efficient, state of the art combustion is needed in the new regulations. Back-end cleanup technology alone is not the best incentive "tool".

CO Emissions

At a CO emissions level of 0.1 lb/MMBtu, retrofitted boilers may have to be converted to FBC, burn a portion of fossil fuels, or install CO reduction catalyst in the SCR body. The most cost effective upgrade of stoker combustion systems, advanced OFA delivery systems, may not be able to achieve 0.1 lb/MMBtu without further treatment. That would exclude access to RECs for many existing plants that cannot find economic justification for installation of FBCs, which cost 3 to 4 times more than OFA delivery system upgrades, have increased parasitic energy loads, longer boiler downtimes to install, and increased maintenance costs associated with erosion by bed material. Additionally, CO is not a critical pollutant in efforts to reduce photo-chemical smog in ozone non-attainment areas. For example, there are existing air permits in California that allow up to 2.0 lb/MMBtu CO emissions on biomass-fired boilers to allow operational flexibility to achieve lower NO_x emissions without the requirement of installing SNCR or SCR. Their focus is primarily on NO_x emissions and not CO emissions in their efforts to improve air quality in ozone non-attainment areas. There are not even CO standards in the NSPS regulations. An effective OFA delivery system, with uniform fuel delivery, adequate furnace residence time, and non-excessive grate firing rates will produce CO emissions from stoker-fired boilers of between about 0.2 and 0.4 lb/MMBtu. We suggest that the CO emissions limit be raised so as not to exclude advanced OFA upgrade technology or force the use of expensive FBC or CO catalyst technology.

D. Output-based emission rates (e.g., lb/kWh or lb/net Btu output of NO_x, CO, PM, and SO_2) would be inclusive of NHR effects. Plants that have high operating efficiency (low NHR) would be allowed to emit higher levels of air pollutants on a lb/MMBtu basis compared to less efficient plants with high NHRs, without exceeding a permit target. In many respects, this is a fairer way to establish emission limits in that the emissions from a plant will be proportional to the amount of power generated by the plant. However, output-based emission rates are not common in the industry and it remains difficult to establish acceptable protocols for fair determination of power generation rates at some facilities.

E. The two-year lead-time to meet new RPS guidelines should only be required for new applications. Changing the requirements of existing plants that have already qualified for REC would add to the uncertainty of developers and prevent projects from moving ahead. There must be some assurance of revenue return to fund the required plant improvements and give incentive to either build new plants or upgrade older plants already in service.

F. The requirements to meet RPS guidelines are extremely costly. It is likely that limiting the receipt of RECs to only three years will not provide enough financial incentive for existing plants to attempt to meet RPS guidelines. Many may be forced to shut down as existing energy contracts run out or be competitively squeezed out by new plants that qualify for

RECs. The results would be a significant loss of renewable energy production resources now built and available to the New England states.

G. The time limits proposed to complete projects that have received Statements of Qualification seem reasonable, as long as the clock does not start until the RPS guidelines have been firmly established and all stakeholders know what the requirements are and that there will be a level playing field for all interested parties.

H. Rather than “relative heat values”, we believe that you mean “relative heat inputs”. For example, if 60% of the total heat input is from an eligible fuel source and 40% is from fossil fuels, RECs would only apply to 60% of the generated electricity. One step further would give consideration to relative boiler efficiencies when burning multiple fuels and proportioning RECs to the electricity generated by eligible fuels, not the heat input by eligible fuels. In the example above, a 60% heat input from biomass firing may only produce 52% of the electricity due to a lower thermal efficiency than fossil fuel and the proportioning of RECs could reflect this factor.

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